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Advanced Cogeneration Research Study

Cogeneration Computer Model Assessment

L. Rosenberg

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Prepared for
Southern California Edison Company
Through an Agreement with
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ABSTRACT

The purpose of this task was to assess cogeneration computer simulation models in order to recommend the most desirable models or their components for use by the Southern California Edison Company (SCE) in evaluating potential cogeneration projects. This report presents a description of existing cogeneration modeling capabilities, identifies preferred models, and recommends an approach to the development of a code which will best satisfy SCE requirements. Of approximately 30 models analyzed, five (CELCAP, COGEN 2, CPA, DEUS, and OASIS) are recommended for further consideration.

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INTRODUCTION AND SUMMARY

A. PURPOSE

The purpose of this task was to assess cogeneration computer simulation models in order to recommend the most desirable models or their components for use by the Southern California Edison Company (SCE) in evaluating potential cogeneration projects. This report presents a description of existing cogeneration modeling capabilities, identifies preferred models, and recommends an approach to the development of a code which will best satisfy SCE requirements.

As defined for this study by JPL and SCE, cogeneration model requirements included accurate technical and economic representation of the user's system both with and without cogeneration; accurate representation of the utility rate structure; straightforward operation; and availability to the SCE technical staff at a reasonable cost.

B. APPROACH

The methodology consisted of a preliminary screening and a secondary analysis. In the preliminary screening, SCE financial analysis models were reviewed. The purpose was to identify formats for interfacing with the cogeneration models. Existing cogeneration models were identified through an extensive data base search. In addition, applicable user guides, manuals, and reports were obtained for most of the models. Following the preliminary screening, a secondary analysis was conducted of models that appeared to further satisfy SCE requirements. Follow-up personal contacts were made with the authors of the programs. Recommendations were then formulated.

C. RESULTS

From approximately 30 studies analyzed, five models (CELCAP, COGEN 2, CPA, DEUS, and OASIS) are recommended for further consideration. JPL recommends running each model with a set of test cases representing the types of fuels,

systems, loads, and users likely to exist in the SCE service territory. Once this is done it will be possible to determine whether an existing model satisfies SCE requirements or whether the best components of the models should then be integrated to form a satisfactory model. The final model would most likely include electrical and thermal load matching algorithms, a detailed representation of the utility rate structure, and the hourly matching and utility tape assessment methodologies of a previously developed JPL energy generation model, DSNX.

SECTION II

PRELIMINARY SCREENING

A. LITERATURE SEARCH

The study team conducted a literature search of the relevant data bases, including DOE, NASA, NTIS, the Engineering Index, the National Energy Software Center (NESC), and several others. Abstracts of approximately 30 studies were selected for the preliminary screening, as summarized in Table 1. (Also see Section V, References.)

B. BASIS FOR SCREENING

The reports of these studies were reviewed and a decision was made as to whether follow-up information would be gathered. This decision was based on the existence of a model and supporting documentation, the degree of model portability, and the fact that SCE was not interested in district heating and cooling models, or in rate structure models. Studies eliminated at this point were #1, Aerospace Corp. (no retrievable model); #4, NASA-Lewis (several non-connected, non-portable models including a rate structure code); #6, Argonne (district heating and cooling models); #11, Oak Ridge (no model); #20, University of Houston (no model); and #24, JPL (non-portable, undocumented code). Several studies (#2, GKCO; #17, Drexel; and #18, Weyerhaeuser) were received too late to be analyzed.

C. EXISTING SCE PROGRAMS

During the preliminary screening phase, the existing SCE financial models were reviewed. Edison has several packages including an interactive financial program system (IFPS) which is a detailed spread sheet similar to Visicalc, a statistical analysis system (SAS), and independent financial models written in BASIC, some of which interface with Visicalc. Since most of the cogeneration models were found to be written in Fortran rather than in BASIC, direct interfacing with the SCE models would require output format adjustments. However, direct interfacing with SCE financial models may not be necessary since most of the cogeneration models were found to have some type of economic analysis.

TABLE 1. PRELIMINARY ASSESSMENT

STUDY # ORGANIZATION	REPORT DATE	STUDY - TYPE OF MODEL	ACCEPTED FOR FURTHER CONSIDERATION
1-Aerospace Corp	04/81	Cogeneration Assessment	No
2-GKCO	09/81	Natural Gas Potential-Economic	*
3-Oak Ridge Asso. Univ.	01/82	Paper Industry-Penetration	Yes
4-NASA-Lewis	03/82	Coal Gas Plant-Rate	No
5-Argonne	06/81	OASIS Applied to Cogeneration-OASIS	Yes
6-Argonne	02/81	District Heating & Cooling-DHCS, DHSM	No
7-Argonne	12/80	Interface with Utility	Yes
8-Brookhaven Nat. Lab	04/81	Commercial Buildings-DOE 2	Yes
9-2D Engineering	03/81	Cogeneration Modeling-CELCAP	Yes
10-Resource Planning Asso.	09/80	Interface with Utility-RPA COGEN	Yes
11-Oak Ridge Natl. Lab	09/78	Conservation-Eng. Economics	No
12-Leeds & Northrup	03/79	Utility Demand Control-Probability	Yes
13-Naval Civil Eng. Lab	09/80	Turbine/Exhaust Boiler Model	Yes
14-Mathtech	02/80	Fuel Cell Designs-Performance	Yes
15-NASA-Lewis	01/82	Superheated Steam Turbines-PRESTO	Yes
16-General Electric	01/81	Fuel Cell Plant	Yes
17-Drexel	05/80	Waste Energy Recovery-Screening, Appln.	*
18-Weyerhaeuser	11/79	Forest Products-GEMS, Linear Prog.	*
19-Mathtech	02/80	Optimization Performance-COGEN	Yes
20-University of Houston	11/79	Chemical Storage	No
21-Rensselaer Poly. Inst.	09/78	Grid Connected	Yes
22-Westinghouse	12/78	Cogeneration Model	Yes
23-Pope, Evans & Robbins	01/78	Electric Utility Model	Yes
24-JPL	11/81	Citrus Processing-COGEN	No
25-Southern Calif. Gas	05/82	Plant Analysis-CPA	Yes
26-General Electric	08/82	Dual Energy Use-DEUS	Yes
27-Synergic Resources	10/82	Cogeneration Options-COPE	Yes
28-Encotech	12/82	Cogeneration Energy Planning Model	Yes
29-Entek		Cogeneration Modeling	Yes
30-Pacific Gas & Electric	06/81	Cogeneration Financial Analysis	Yes

*Report not received in time to include in study.

SECTION III
SECONDARY ANALYSIS

A. APPROACH

After completing the preliminary screening, the study team assessed the 21 remaining models by completing the checklist in Table 2 on hardware, software, and availability characteristics. This information was based on the user guides and on discussions with the developers or sponsors of the models. Each model was evaluated as to capability, compatibility, accuracy, and availability.

B. MODEL CAPABILITIES

The first step in the secondary analysis was to classify the models according to capability. The breakdown by capability is shown in Table 3 (for consistency, the study numbers are the same as on Table 1). Since in this study SCE was interested only in the first group (cogeneration vs. demand profile), these models were selected for further study. Other capability groups included regional market assessment tools, detailed building energy consumption models, a plant operation analog model, and design point performance models. Some models within the first group were found to perform financial analysis only. These were also eliminated from future consideration. Other models in this group usually perform the full range of functions, that is, they generate output data for the type of cogeneration system under consideration, match the output to a demand profile, calculate financial figures of merit for the cogeneration system, and compare the cogenerated electricity costs with utility-generated electricity costs. The approach to matching energy availability to loads may be on an hourly basis for sample periods or for every hour of the year. Detailed characteristics of the cogeneration vs demand profile models are summarized in Table 4.

C. COMPATIBILITY WITH SCE HARDWARE AND LANGUAGE

The second step was to assess the codes on the basis of compatibility with SCE hardware and language, that is, IBM Fortran. It was found that codes not written in Fortran include parts of Mathtech's COGEN 2 (Assembly language);

TABLE 2. SURVEY OF COGENERATION COMPUTER PROGRAMS

1. Name of Program:

2. Person(s) responsible for Program:

3. Intended purpose of program (i.e., what program does; include description of typical output):

4. Brief general description of program structure:

5. Computer language utilized:

6. On what system is the program presently run:

7. Approximate running time and cost per run (daytime rates):

8. Estimated complexity and ease of operation:

9. Status of program development:

10. Availability of code:

11. Availability of documentation:

12. Other Comments:

TABLE 3. MODEL CAPABILITIES

STUDY #	COMPANY	MODEL NAME	FUNCTION (e.g., TYPE OF MATCHING)
COGENERATION VERSUS DEMAND PROFILE MODELS			
5 -	Argonne	OASIS	Hourly; optimization
7 -	Argonne	RELCOMP	Sample periods
9,13 -	Naval CE Lab	CELCAP	2 days/month
10 -	Resource Planning Asso.	RPA COGEN	13 days/yr; no utility capability
19 -	Mathtech	COGEN 2	Sample periods; optimization
21 -	Rensselaer Poly. Inst.	Cogeneration evaluation	Hourly
22 -	Westinghouse	Energy balance	Energy balance equations
23 -	Pope, Evans & Robbins	Cogeneration	Hourly
25 -	Southern California Gas	CPA	2 days/month
26 -	General Electric	DEUS	Sample periods
27 -	Synergic Resources	COPE	Financial analysis only
28 -	Encotech	Cogeneration and energy planning	2 days/month
29 -	Entek	UTPAY Cash Flow ENTEK1	Electric bills Financial analysis only System impacts
30 -	Pacific Gas & Electric	Cogeneration financial analysis	Financial analysis only
REGIONAL MARKET ANALYSIS MODELS			
3 -	Oak Ridge	Penetration	Regional paper markets
21 -	Rensselaer Poly. Inst.	Optimal generation	Regional analysis; optimization

TABLE 3. MODEL CAPABILITIES (Continued)

STUDY #	COMPANY	MODEL NAME	FUNCTION (e.g., TYPE OF MATCHING)
BUILDING ENERGY CONSUMPTION MODELS			
8	- Brookhaven	DOE 2	Hourly building analysis
14	- Mathtech	Fuel Cell	Fuel cells in buildings
PLANT OPERATION MODELS			
12	- Leeds & Northrup	Analog model	Replicates cogeneration system and plant
DESIGN POINT PERFORMANCE MODELS			
15	- NASA-Lewis	PRESTO II	Turbines; no part load
16	- General Electric	MCFC	Carbonate fuel cells

TABLE 4. COGENERATION VS. DEMAND PROFILE MODELS - DETAILED CHARACTERISTICS

COMPANY	MODEL	CAPABILITY	LANGUAGE	SYSTEM	LAST USE	PORTABLE	AVAILABILITY
Argonne	OASIS	Cogen vs Utility, Hourly matching; optimization	Fortran	Various	Current	Yes - In Spring	Yes - In Spring
Argonne	RELCOMP	Cogen vs Utility; Hourly based on load duration curve (26 periods).	Fortran	IBM	1980	Yes	NESC (early version); charge
Naval Civil Engineering Lab	CELCAP	Cogen vs utility on hourly basis; 2 days/mo.	Fortran	CDC	Current	Yes	Yes, no charge
Resource Planning Association	RPA COGEN	Stand-alone cogeneration analysis; 13 days - hourly	Fortran	CDC	1980	Yes	EPRI
Rensselaer Poly Institute	Cogen Eval	Cogeneration vs utility; Hourly matching	Fortran	PDP-15, IBM	1979	No	No
Mathtech	COGEN 2	Annualized cost. Cogen vs utility; LP optimization; Typical days. 22 time Per.	Assembly, Fortran	IBM	Current	Cogen 2- No	Cogen 3 (EPRI in Spring)
Westinghouse	Energy Bal	Cogen vs utility based on energy balance equations.	APL	Scien- tific time share	1978	NA	NA
Pope, Evans & Robbins	Cogeneration	Cogen vs utility on hourly basis.	HP	HP-97	1978	No	Yes; $6-7K including HP-97.
Southern California Gas	CPA	Cogen vs utility on hourly basis; 2 days/mo.	Fortran	CDC Cyber- net	Current	No	License or lease; no code
General Electric	DEUS	Cogen vs utilty on hourly basis; 36 time periods.	Fortran	IBM	Current	Yes	EPRI; SCE has tape
Synergic Resources	COPE	Institutional, regulatory, and financial analysis of cogeneration.	Fortran	IBM	Current	Yes	EPRI, SCE has tape

TABLE 4. *COGENERATION VS. DEMAND PROFILE MODELS - DETAILED CHARACTERISTICS (Continued)*

COMPANY	MODEL	CAPABILITY	LANGUAGE	SYSTEM	LAST USE	PORTABLE	AVAILABILITY
Encotech	Cogen. + Energy Planning	Cogeneration vs utility - cash flow; hourly 2 days/mo	Basic	Prime	Current	No	Interactively; no code, charge
ENTEK	UTPAY	Evaluates electric bills with + without cogeneration	Fortran	Micro	Current	Yes	Yes; charge
ENTEK	Cash Flow	Cogeneration investment analysis.	Fortran	Micro	Current	Yes	Yes; charge
ENTEK	ENTEK 1	System impact on rates, revenue, capacity.	Fortran	Various	Current	Yes	Yes; charge
Pacific Gas & Electric	Cogen Fin. Analysis	Economic analysis of cogeneration; avg. time periods		CDC Cyber-net	Current	No	CDC Cybernet; no code

Pope, Evans & Robbins Cogeneration Model (HP calculator language); Encotech's Cogeneration and Energy Planning Model (BASIC); and Westinghouse's Energy Balance Model (APL). Most of the models are operational on mainframe computers or are available from a time-share system. ENTEK 1 is operational on several mainframe computers. The two other Entek models work on micro-computers, which gives them an advantage over the other models with respect to computer running costs.

D. MODEL ACCURACY

The third step was to assess the models on the basis of modeling accuracy. Most models match electrical and thermal energy generated against demand on an hourly basis or for some sample time period, usually two days per month. The use of sample time periods can result in inaccuracies when the nature of the demand profile is such that large peaks occur on an occasional basis. This can be further magnified by the applicable utility billing structure if the large peak demands occur during high billing periods. Load averaging may also result in the undersizing of equipment.

In order to assess the potential magnitude of the load averaging error, a JPL model, DSNX, was run for the JPL Deep Space Network tracking station at Goldstone, CA. This model reads electrical demand tapes and closely replicates electric bills of SCE customers. When actual electric hourly usage data was evaluated for 19 months in 1980-81, the DSNX code provided a result that was within 1% of the actual bills. When average monthly demand values were used, the calculated bills were 7.4% lower than the actual bills. This does not include any thermal averaging losses or any losses due to the averaging of electrical vs. thermal sensitivities.

Several models were identified which do not use average time periods: Westinghouse's Energy Balance model (#22), which uses energy balance equations; RPI's Cogeneration Evaluation (#21) and Argonne's OASIS (#5), which can match availability and demand on an hourly basis for periods of up to a year.

The accuracy of the engineering representation of cogeneration systems appeared to be satisfactory. Most of the codes contain engineering data bases for various cogeneration systems or allow the user to input his own or make any desired changes. Systems typically represented include steam turbines, gas turbines, fuel cells, diesel engines, and combined cycles.

E. AVAILABILITY OF THE MODELS

The fourth step in the secondary analysis was to assess the codes on the basis of availability. The availability of a code can be restricted by proprietary rights, prohibitive costs, or limited portability. In some cases a model could be run but its computer code could not be studied in-depth. This is a drawback since a user could not be sure what is occurring within the model when it is being exercised. Some models have been developed for the Electric Power Research Institute (EPRI) as noted in Table 4. SCE is a member of EPRI, and these models are usually more available than non-EPRI models. An EPRI project (Team-Up) is making a set of EPRI-developed models machine-independent for facilitated use by EPRI members.

F. RESULTS OF SECONDARY ANALYSIS

Based on these factors, eight models were eliminated from further review for the reasons presented below:

Model	Rationale for Rejection
7 - RELCOMP (Argonne)	Cogeneration algorithm not documented and not polished. Early version available from NESC does not include cogeneration.
10 - RPA COGEN (RPA)	Available from EPRI, but is very simple and does not include utility generation.
21 - Cogeneration Evaluation (RPI)	Input is prepared on PDP-15 (not done for 3-4 years) while model is run on IBM. Not very portable; tape copy difficult to get.

22 -	Energy Balance (Westinghouse)	Simple, non-validated model which has not been used since 1978.
23 -	Cogeneration (Pope, Evans & Robbins)	Designed for an obsolete calculator (HP-97). When in use (3-4 years ago), it was project specific. Cost was $6-7k including HP-97.
28 -	Cogeneration and Energy Planning (Encotech)	Written in BASIC but is available in interactive format only; no code.
29 -	UTPAY, CASH FLOW, ENTEK1 (Entek)	UTPAY and CASH FLOW are financial models. High costs: Entek services - $5-10k; UTPAY model - $2k; ENTEK 1 model - $40-50k.
30 -	Cogeneration Financial Analysis (Pacific Gas & Electric)	Financial analysis is specific to Pacific Gas & Electric. Available in interactive format only; no code.

The models of interest, therefore, were reduced to five: OASIS, CELCAP, COGEN 2, CPA, and DEUS. A summary of their major characteristics is presented below. Detailed information obtained from model user guides and from other documentation is presented in the Appendix.

Model		Major Characteristics
5 -	OASIS (Argonnne)	Electric or thermal dispatch; can do hourly matching for a year; optimizes; utility representation not very detailed; still under development for DOE - available in Spring 1983 for no charge.
9, 13 -	CELCAP (Naval CE Lab)	Stored data on steam turbines, combustion turbines, diesels; thermal or electrical dispatch; available for no charge; Navy will run sample cases for no charge.

19 -	COGEN 2 (Mathtech)	Stored data on steam turbines, combustion turbines, diesels, gas turbines, fuel cells; linear programming optimization; includes specialized IBM software packages that cost $1,200-$1,400/month; will make sample run if SCE pays for running costs; new version - COGEN 3 being developed for EPRI's Team-Up project will be machine independent; available in Spring 1983.
25 -	CPA (Southern California Gas Co.)	Stored data on steam turbines, gas turbines, reciprocating engines, combined cycle; thermal or electrical dispatch, base load, peak shaving, total energy; Southern California Gas will run it for a fee (~$2,500/case) or may give it out on a licensing basis; SCG has agreed to run sample cases for no charge.
26 -	DEUS (General Electric)	Stored data on steam turbines, coal/gas combined cycle, fuel cells, gas turbines, diesels; thermal and economic dispatch; done for EPRI; currently operational on JPL Univac computer.

Once these final models were identified, the next step was to run them for several representative cases in order to determine if they give consistent answers. However, within the scope of the present survey, only DEUS was run on the JPL Univac computer for a sample case in the DEUS users guide. This effort encountered serious difficulties. The tape with the DEUS model which was given by SCE to JPL originated at EPRI and was supposed to be portable. There were errors in the Fortran code, a lack of adherence to Fortran 77 standards, specific problems involved in mounting a code which came from an IBM computer onto JPL's Univac machine, and there were difficulties in exercising the code (the specifics of these problems have already been forwarded to SCE). It should be noted that this is not an unusual circumstance. In fact, what is unusual is when a model can be put on a new system with no adjustments. Generally, this is due to language or machine characteristics that are particular to specific installations. (EPRI's Team-Up project is trying to alleviate this situation for codes used by its members.) In the course of overcoming the programming obstacles, about 1-2 weeks were lost. However, it was finally possible to replicate a sample case

given in the DEUS users guide. This example was for a typical gas/oil burning utility with average loads, variable utility rates, and simultaneous buying and selling of electricity. The systems evaluated included a no-cogeneration case with a coal-fired boiler, and cogeneration cases that consisted of a coal-fired steam turbine, a gas-fired gas turbine, and a gas-fired combined cycle system.

SECTION IV
CONCLUSIONS AND RECOMMENDATIONS

The conclusions of this assessment are:

1. Five models (CELCAP, COGEN 2, CPA, DEUS, and OASIS) appear to have components which meet Edison requirements and should be evaluated in more detail.

2. Averaging of electrical and thermal demands can lead to inaccuracies which may result in the selection of undersized cogeneration equipment.

3. Portability problems should be expected when a model is transferred from one computer system to another.

4. The cogeneration engineering evaluation in the models appears to be satisfactory.

The problem of portability can be minimized if test cases are run by the originator of the model. This should be possible with CELCAP, COGEN 2, CPA, and OASIS. (DEUS is running now on a JPL computer.) However, if SCE desires to obtain its own capability, it would have to acquire and operate these models at some point.

The next step in obtaining a reliable model for SCE is a detailed assessment of CELCAP, COGEN 2, CPA, DEUS, and OASIS. This would include a detailed code evaluation, several test runs for each model, and a comparison of results with data representative of cogeneration technologies and industrial loads in the SCE service territory. Then the best components can then be integrated. The major components would most likely include hourly electrical and thermal load matching algorithms, a detailed representation of the utility rate structure, and hourly matching and tape reading methodologies similar to those of the JPL DSNX code.

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38. F. E. Wicks, et al, "Development and Application of Total System Methods for Evaluation of Grid Connected Cogeneration," Proceedings of 1978 IEEE/ASME/ASCE Joint Power Generation Conference, IEEE Power Engineering Society, New York, NY 10017 (Sep. 1978).

APPENDIX

NOTES ON PREFERRED MODELS

NOTES ON PREFERRED MODELS

The purpose of this Appendix is to present information on the preferred models: CELCAP, COGEN 2, CPA, DEUS, and OASIS. Except where noted, the information on the models has been taken from user guides or other documentation, usually verbatim, and has not been verified by JPL through code analysis or test cases.

A. CELCAP

1. Overview

Developed at a cost of $70,000, CELCAP is a preliminary screening tool intended to permit rapid consideration of many cogeneration alternatives. It is intended to be used at U.S. Naval installations throughout the United States, and possibly worldwide. After running CELCAP, the Navy would then run another program (unspecified) to choose between the better cogeneration alternatives for a particular site.

2. Major Features

According to the CELCAP user's guide (Reference 8), the major features of CELCAP are as follows:

- Analyzes steam turbine (single extraction or back pressure), combustion turbine, and diesel systems;

- Handles any combination of five (5) or less engines;

- Compares operation of system assuming three different control modes (modulation to follow thermal load, modulation to follow electrical load, and constant operation at full load);

- Analyzes effect of installing peaking engines as well as cogeneration units;

- Accurately predicts off-design performance of steam turbine and combustion turbine engines;

- Predicts cost of purchased electrical power and revenues from sale of power to the grid with rate structure algorithm (algorithm can be readily modified for different rate structures);

- Input data includes typical steam and electrical load profiles for work days and non-work days of each month, engine design point data, fuel prices, rate data for purchased electricity, and assumed escalation rates for fuel, power, and O&M;

- Output data includes comparisons of the system's steam and electrical outputs vs. loads (plots and tabulation), monthly and first-year breakdown of costs, and annual cost projections throughout the life cycle;

- User is responsible only for providing site specific information on the thermal and electrical load patterns and the electrical utility rate structures.

3. Inputs and Outputs

CELCAP is organized into five sections. The required inputs and outputs are presented below, as taken from Reference 8.

SECTION 1. Determine "Limiting" System Performance

Input: Engine mix for analysis
Design parameters of each system
Site atmospheric information

Output: Limiting electrical and steam production and fuel consumption

Capability: Combustion turbines with exhaust boilers

SECTION 2. Determine Steam And Electrical Loads

This algorithm is site-specific.

SECTION 3. Compare Loads And System Performance

Input: Mode desired
Identify peaking unit operation periods

Output: Electrical and steam production and fuel consumption of each engine in response to loads and control mode
Purchase or sale of electrical power
Make-up steam from fixed boiler
Amount of excess steam produced

Capability: Control modes: Full throttle
Modulation with electrical load
Modulation with steam load

SECTION 4. Calculate Annual Costs

Input: Fuel costs for each type system
O&M costs for each type system

Output: Annual fuel costs: Combustion turbines
Diesels
Steam turbine boilers
Fired "make-up" boilers

Annual O&M costs: Combustion turbines
Diesels
Steam turbines and boilers
Fired "make-up" boilers

Purchased electricity costs
Revenue from sale of electrical power

The algorithm for cost of purchased electrical power and revenue from sale of electrical power is site-specific.

SECTION 5. Calculate Life Cycle Costs (LCC)

Input: Short and long term escalation rates, fuel, O&M
Key years: Year of "present" worth
Installation year
Year of change in escalation rates
End of economic life
Discount rate

Output: Future value for each output of SECTION 4
Total LCC over economic life

4. Availability and Point of Contact

CELCAP is available at no charge to the public. It is written in Fortran and runs on a CDC computer at the Naval Civil Engineering Laboratory (CEL).

The contact at CEL is:

Dr. Gene Cooper
Civil Engineering Laboratory
Mechanical Systems Division
Code L63
Port Hueneme, CA 93043
Telephone: (805) 982-4675

B. COGEN 2

1. Overview

COGEN 2 is one of several models developed for EPRI through an original $750,000 project. (A code-specific breakdown of development costs is not available.) COGEN 2 is fully developed and has been tested in five case studies but is not portable. COGEN 3 is a portable version expected to be available from EPRI as part of its Team-Up project by June 1983.

According to Reference 21, COGEN 2 is a design, costing, and economic optimization model with associated data bases. COGEN 2 considers the problems of equipment selection and operation, fuel selection, and purchase or self-generation of electricity. It solves for the design and operating schedule which is able to supply all steam and electricity requirements at lowest cost. It can be applied to the analysis of either new or existing facilities.

In order to make a run of COGEN 2, the model must first be provided with three kinds of input data:

- A description of the energy requirements for the facility to be analyzed (i.e., the pattern of its steam and electric demands over time).

- A description of the energy conversion technologies available for use by the plant in terms of performance and capital costs (values can also be taken from the COGEN 2 data base).

- A set of prices for the different fuels, purchased electricity, equipment, and money.

COGEN 2 is then able to determine:

- Which technologies should be used (or installed);

- How the equipment should be operated in each time period;

- How much fuel and purchased electricity will be consumed;

- How much electricity will be sold;

- How much the system and its operation will cost.

2. Design Criteria

COGEN 2 selects the equipment and operating program which can supply the required process steam and electricity at lowest cost. The cost concept employed is that of a levelized annual cost. Investment decisions based on levelized cost will be equivalent to decisions based on discounted present value methods. Cost minimization is used as the decision criterion since it most likely reflects the behavior of individual firms. However, other criteria, such as cost minimization subject to a capital budget constraint, can be easily incorporated in the model.

In determining the lowest cost alternative, the COGEN 2 model automatically considers all possible design alternatives such as:

- Sizing equipment to match the thermal load;
- Sizing equipment to match the electric load;
- Using cogeneration to shave peak electric loads;
- Simultaneous buy/sell arrangements with the utility.

If desired, the model can also be constrained to select only those designs which would be "qualified cogeneration facilities" under the Federal regulations (18 CFR Part 292) implementing the Public Utility Regulatory Policies Act of 1978 (PURPA).

3. Technologies

The COGEN 2 data base includes two sets of technologies: state-of-the-art (SOA) technologies and advanced technologies. Included among the SOA technologies are most of the commonly used types of power-producing equipment, and commonly used design configurations for each of the equipment types. The SOA technologies included are:

- Fossil fuel-fired steam generators (boilers);
- Waste fuel-fired steam generators;
- Steam turbine generators;
- Combustion turbine generators;
- Diesel engine generators.

The advanced technologies represented in the COGEN 2 data base include:

- AFB/PFB steam generators;
- Advanced open cycle gas turbines;
- Closed cycle gas turbines;
- Combined cycles;
- Molten carbonate fuel cells.

4. Cost and Performance Parameters

For each device type and size, the following cost and performance parameters are included in the COGEN 2 data base:

- Capital cost for purchase and installation;
- Annual operation and maintenance cost (O&M) exclusive of fuel costs;
- Fuel consumption at rated output;
- Fuel consumption at less than rated output;
- Minimum and maximum output (steam or electric);
- Minimum and maximum exhaust flows (steam turbines only);
- Maximum throttle flow (steam turbines only).

The effects of investment tax credits, interest during construction, depreciation methods, taxes, other miscellaneous costs, and the cost of money are all incorporated into a fixed charge rate which is applied to the original

capital cost. The parameters used in calculating the fixed charge rate can be varied from run to run. Thus, different methods of financing and ownership can be examined, as well as different tax regulations.

5. Fuel Prices

COGEN 2 incorporates four purchased fuels, including:

- Residual oil (petroleum or coal-derived);
- Distillate/diesel oil (petroleum or coal-derived);
- Gas (natural or coal-derived);
- Bituminous coal.

The model also incorporates waste fuels such as bark or hogged wood in the paper industry. The waste fuels can be used to generate steam in appropriately designed steam generators. Typically, the waste fuels are available at a zero price and in limited quantities. However, these assumptions are not required.

6. Purchased Electricity

Most utilities sell electricity according to rate schedules which take into account both the quantity of electricity purchased (kWh) and the peak demand (kW) which the customer imposes on the utility. This is especially true of sales to industrial customers. Utilities which use a "Hopkinson" tariff compute a customer's bill by applying separate charges for energy (kWh) and for demand (kW). The energy and demand charges may vary with the quantities involved, and with the time when the purchase occurs. For example, under a declining-block Hopkinson tariff, the price per kWh and the price per kW decline with increases in consumption. An additional fixed cost, or "customer charge," is also often applied regardless of the level of use.

Another widely used tariff is the "Wright" tariff. Under this form of tariff, the customer is billed on the basis of kWh consumed. However, the price per kWh may decline both with increased quantities purchased and with increases in the kWh consumed per kW of peak demand.

Still a third arrangement is to price the electricity according to the time of use. With this approach, rates are typically higher during the day and lower at night. Rates may also be higher in the summer (or winter) months if the utility experiences its peak annual demand in the summer (winter).

All of these different approaches have been analyzed successfully using COGEN 2.

7. Purchased Standby Capacity/Reliability

Some facilities may require a highly reliable supply of electricity. Hence, self-generation in these industries is made reliable through the provision of backup generating capacity from the utility. Both of these options are allowed in COGEN 2, and the model can be used to identify which method is lower in cost.

Utilities which permit industrial customers to buy electricity on a standby basis generally have a separate tariff for this service. Under these tariffs, a monthly charge is typically made for the amount of standby capacity for which the customer contracts. Standby capacity tariffs typically look like the demand (kW) part of a Hopkinson tariff. This is the approach currently used in COGEN 2.

8. Electricity Sales

COGEN 2 allows a cogeneration system the option of selling electricity back to the electric utility grid. Revenues obtained from sales are then deducted from the annual energy cost of the plant. This means that the selection of the minimum cost system may be influenced by the price at which electricity can be sold.

The price for sales, the so-called buy-back rate, is a parameter of COGEN 2 that can be varied from run to run. As currently formulated, the buy-back rate can vary with time of delivery or be fixed at some average price per kWh.

9. Process Demands

Process steam and electricity demands are represented in COGEN 2 as constraints. That is, the energy equipment chosen, together with any purchased electricity, must be able to satisfy all of the facility's demands in every demand situation. Different demand situations are represented by "typical" hours or time periods in the model.

While the number of time periods in the model can be arbitrary, experience has shown that four to eight are typically required. With eight periods, one can represent all combinations involving: high or low electric loads, high or low steam loads, and peak or off-peak electric rates. The largest number run to date was 22 time periods.

10. Availability and Point of Contact

When available from EPRI, as part of the Team-Up project, COGEN 3 will be machine-independent. For more information on the technical aspects of the model, contact:

Mr. E. H. Manual, Jr.
Mathtech Inc.
14 Washington Road
Princeton Junction, NJ 08550
(609) 799-2600 x2235

For information regarding the availability of the model from EPRI, contact:

Mr. Robert Ciliano
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94304
(415) 855-2000 x2216

C. CPA

1. Overview

The Southern California Gas Company developed the CPA (Central Plants Analysis) program by modifying an existing model at a cost of $75,000. Because it is intended for use primarily within the Gas Company, relatively little detail is available on the CPA model. A Gas Company brochure describes the model as a tool for optimizing the configuration and operation of cogeneration systems.

CPA has stored data on gas turbines, steam turbines, and reciprocating engines. Topping cycle, bottoming cycle, and combined cycle configurations are considered. Non-gas fuel utilization systems are not discussed in the brochure. Operation modes include both thermal and electrical dispatching to match loads, base load dispatch, peak load dispatch, and total energy utilization. The electric utility intergration has the following options: buy all/sell all, sell excess only, time-of-day rates. The economic analysis is limited to life-cycle cost, with consideration of tax benefits and various financing arrangements.

2. Availability and Point of Contact

CPA may be available through a licensing arrangement with Southern California Gas Company, or they will run the model for a fee of approximately $2,500 per case. The point of contact is:

Mr. David Berokoff
Southern California Gas Company
810 S. Flower Street
Los Angeles, CA 90017
(213) 689-3603

D. DEUS

1. Overview

The DEUS model (Dual Energy Use System) was developed and validated by the General Electric Company for EPRI at a cost of approximately $200,000. It is a screening tool based on general system characteristics, but it can also be used for more detailed application studies when input data for specific systems are used.

The DEUS cogeneration evaluation methodology is based on a comparison of two alternatives, no-cogeneration and cogeneration. In the no-cogeneration system, all electricity to the industry is supplied by the utility. Process steam is supplied by a process boiler supplemented by a waste heat boiler that utilizes any waste heat available from the plant. In the cogeneration system, the steam from both the waste heat boiler and the energy conversion system is used for process heat and electricity. An auxiliary fuel boiler can also be added to generate process steam. The utility can supply electricity to the industry or buy electricity from the cogeneration system owner or own the cogeneration system and sell steam to the industry.

A single-year economic dispatch is performed for each cogeneration system using cost data for the first year of plant operation. This economic dispatch for the first year is assumed to remain the same for each year of operation. Operating expenses and revenues, however, are not assumed constant. They vary through time and are calculated using the first year dispatch results; yearly cost data (fuel costs, utility electric rates, etc.) are specified as program input.

The DEUS program data base includes system performance and cost information; data on eight fuel types; a set of utility rate data for a utility with high oil use, including PURPA rates; industrial power energy and demand rates; marginal production costs and capacity values; industrial steam and power demand; economic data; and data on ownership.

2. Cogeneration Systems

When used as a screening tool, the DEUS data base provides performance and cost information for a base case no-cogeneration system, and for each of the following cogeneration systems:

- Boiler-steam turbines;
- Integrated coal-fired gasifier-combined cycle;
- Phosphoric acid fuel cell with a supplementally-fired heat recovery steam generator (HRSG);
- Simple cycle gas turbine with HRSG;
- Combined cycle with clean fuel;
- Medium-speed diesel with HRSG and open cycle heat pump.

The steam turbines are both low- and medium-pressure, and non-condensing and condensing multi-auto extraction. When using coal, both pulverizd coal-fired boilers with flue gas treatment and atmospheric fluidized bed boilers are considered. The system performance includes design-point and part-load performance for three steam pressures and a range of available heat to power ratios.

3. Economic Evaluation

The program evaluates the performance and economics of cogeneration systems under several ownership options - industrial, utility, and third-party ownership, but with emphasis on the utility point of view. For both industrial and third-party ownership, a standard discounted cash flow (DCF) rate of return methodology is used, with due consideration to any available tax credits, and calculates internal rate of return for each cogeneration alternative. The analysis of an industry-owned cogeneration system assumes that the industry (a) sells excess electricity to the utility, or (b) sells

all generated power to the utility and buys back all site power ("buy all/sell all"). For industrial ownership, the internal rate of return is calculated for the incremental investment for cogeneration as compared to no-cogeneration. For third-party ownership, annual cash flows reflect revenues from electricity sales to the utility and steam sales to the industry. The internal rate of return for this case is calculated for the entire plant investment. Utility cost impacts are determined for both non-utility and utility ownership.

4. Availability and Points of Contact

A copy of the DEUS program was provided by SCE, and run on the JPL Univac computer for a sample case in the DEUS users guide. This effort encountered serious difficulties. The tape with the DEUS models originated at EPRI and was supposed to be portable. There were errors in the Fortran code, a lack of adherence to Fortran 77 standards, and specific problems in getting the model to run on the Univac machine. (See Section III.E for more details.) The problems were reported in detail to SCE. Apparently there are several versions of the DEUS program; a supposedly clean version is now available at no charge from EPRI.

The point of contact is:

Dr. S.D. Hu
Energy Management and Utilization Division
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, CA 94304
(415) 855-2000

E. OASIS

1. Overview

OASIS is in the process of final documentation and debugging. Total costs to date exceed $250,000. It is expected to be available in June 1983 if funding is approved by DOE.

The OASIS (Optimization and Simulation of Integrated Systems) computer program was developed by Argonne (and previously, Consultants Computer Bureau) as an aid in analyzing and designing community energy systems. It simulates plant operation in response to user-supplied demands, either optimally or according to a user-defined operating strategy. In the optimization mode, it minimizes resource energy input with user-assigned weights or operating and maintenance costs. The simulation assumes quasi steady-state operation for each time increment, generally hourly, over time periods selected by the user.

For the plant to be simulated, the user must specify and size each piece of equipment installed and must connect equipment and energy inputs or outputs to each other, as appropriate. In some cases, the component operation may depend, in addition to the load imposed on it, on certain environmental parameters, such as ambient air temperature. The source of such information also is given by the user, either explicitly or by default.

The OASIS code package consists of four separate programs that are linked together by the information flowing through them. These four programs proceed as follows:

1. Process the input data;

2. Simulate the system according to optimal or user specified strategies;

3. Perform economic analyses for specified simulations; and

4. Process the results to produce a printed or graphical output.

2. Input Program

OASIS contains an extensive library of generic component subroutines that model representative central plant equipment by using part-load performance curves. Defaults exist for all the required performance data. New equipment routine models, written in Fortran, may be entered into the input stream for any given job.

3. Plant Program

The plant program analyzes the given system configuration and constructs a network through which energy flows to meet the loads or demands on the plant. Two basic building blocks make up the network: "equipment" and "pools." "Equipment" routines are transfer functions containing input/output relationships; "pools" are used to record, mix, and allocate flows of energy among the pieces of equipment.

4. Economics Program

OASIS is able to simulate specified portions of the year and extrapolate from them to a full year's run. It also escalates the costs of any general plant operation, equipment, or energy whose specific cost reference year predates the plant cost base year. With this information, it is then able to execute analyses of any year and project life.

Included in the life cycle calculations are capital costs and operating costs in current dollars. Capital costs include costs of debt, equity, depreciation, taxes, and insurance. Operating costs are made up of fuel costs, labor and materials costs, cyclical equipment costs, and administrative and other overhead costs. Present values of costs also are computed for each plant year of life.

5. Reports Program

Economics reports may be selected to detail cost results for the cost base year of each energy media supplied to or sold from the plant. Annual equipment cost figures and those for the life of the plant may be given with all escalation rates taken into account. Also, a life-cycle table that contains the capital, equipment, and energy-related cost and credit items may be printed.

6. Availabililty and Point of Contact

If OASIS documentation is completed, the model will be available from Argonne at no charge. It will be written in Fortran compatible with IBM, CDC 7600, and VAX systems. The running time is approximately three to four minutes for a full year's data. The point of contact is:

Ms. Dorothy J. Bingaman
Energy and Environmental
Systems Division
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
(312) 972-3978